REBUTTAL TESTIMONY

OF

R. SCOTT PARKER

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

DOCKET NO. 2020-125-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Scott Parker. My business address is 601 Old Taylor Road, Mail Code J37, Cayce, South Carolina 29033. I am employed by Dominion Energy South Carolina, Inc. ("DESC" or the "Company") where I am Manager of Transmission Planning.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I am a graduate of Clemson University with a Bachelor of Science degree in Electrical Engineering. I also hold a Master of Business Administration degree from the University of South Carolina. I am a registered Professional Engineer in the State of South Carolina.

I began working for the Company in 1990 as an engineer in Generation Planning. I was promoted to Manager of Operations Planning in 2012 and to my current position of Manager of Transmission Planning in 2018.

Q. ARE YOU A MEMBER OF ANY INDUSTRY COMMITTEES FOR SYSTEM RELIABILITY ASSESSMENT OR PLANNING?

A. Yes, I am currently a representative for DESC on the Southeastern Reliability Corporation ("SERC") Engineering Committee and the SERC Planning Coordination Subcommittee. I am the current chair of the Carolinas Transmission Coordination Agreement Power Flow Study Group. I am also a member of the Eastern Interconnection Planning Collaborative Technical Committee.

All of these committees are directly involved with assessing the current and future capabilities of the integrated transmission grid in North America, the Southeast, and the Carolinas.

Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGER OF TRANSMISSION PLANNING.

A. I am responsible for managing the engineers who prepare the planning and associated analyses of the DESC electric transmission system to ensure compliance with required transmission planning and reliability standards and criteria, as discussed below. It is our duty to ensure the safety, reliability, adequacy and cost effectiveness of the internal DESC transmission system as well as the interconnection transmission facilities with neighboring utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not previously testified before this Commission.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. The purpose of my testimony is to respond to the direct testimony of Ted McGavran on behalf of the South Carolina Energy Users Committee ("SCEUC") and South Carolina Department of Consumer Affairs ("DCA") and Michael Seaman-Huynh on behalf of the South Carolina Office of Regulatory Staff ("ORS"). In it, I describe for the Commission the Transmission Upgrade Projects that were originally undertaken as part of the project to construct two new nuclear units at the V.C. Summer site (the "NND Project") that have been placed in service to meet the demands of our customers. My testimony explains why these Transmission Upgrade Projects are currently used and useful assets to DESC.

Q. PLEASE DESCRIBE THE GEOGRAPHY OF DESC'S TRANSMISSION SYSTEM.

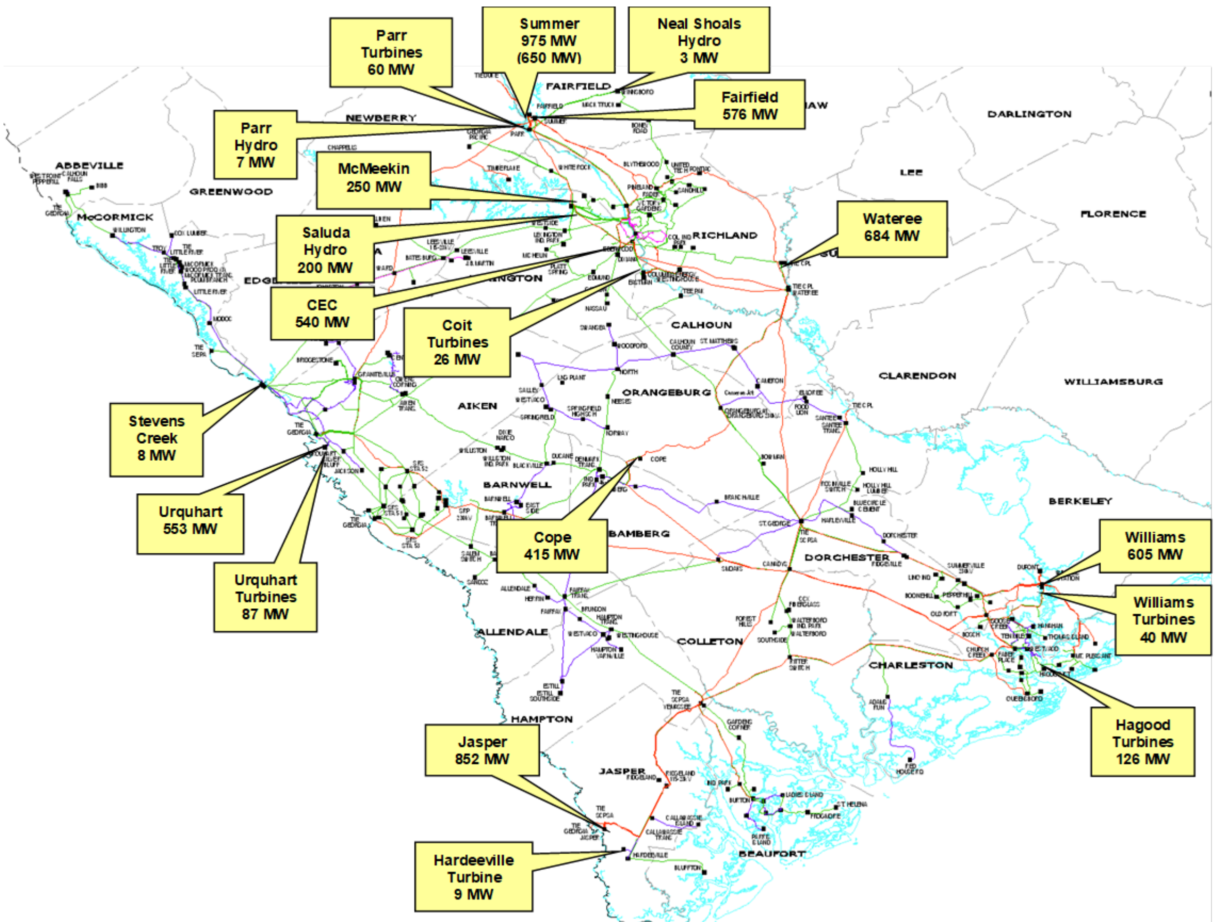
A. DESC's transmission system has always generally been divided into a northern and southern region. The northern region includes the Columbia, Town of Lexington, Orangeburg, Batesburg-Leesville, and Aiken areas. The southern region includes the South Carolina Low Country including the Charleston, Summerville, Mt. Pleasant, Walterboro and Beaufort areas. The Company's transmission system links the northern and southern load centers and is configured to provide for the reliable flow of power from north to south. The Transmission Upgrade Projects that were planned in 2008 recognized this geography and improved the link between the two principal parts of our system, and improved our ability to provide service into the Columbia area. The general configuration of our transmission system has not changed.

Q. HOW ARE DESC'S GENERATION ASSETS DISTRIBUTED WITHIN THE SERVICE TERRITORY?

A. For a number of reasons, including the historic availability of high-volume natural gas pipelines, rail service, land-use patterns and environmental restrictions, the majority of DESC's generation resources are located in the northern transmission region. For that reason, principal power flows on the system are north to south. There are, however, times when power flows are reversed and generation located in the southern region supports loads in the northern region. This occurs most often in off-peak periods when major generating units in the northern transmission region are out of service for planned outages such as nuclear refueling and maintenance but also when unplanned outages occur. These flows between the northern and southern transmission regions are substantially carried along a continuous path created by the Transmission Upgrade Projects, which establish a backbone through the center of the DESC transmission system. Figure A illustrates the location of DESC generation assets and shows how the assets are generally situated in the midlands region, and the majority of these, more than 1,700 MWs, are located northwest of the City of Columbia. Wateree is the only generating station located on the east side of

Columbia. Only 771 MWs of generation are located in the vicinity of Charleston. One unit, Williams Station, represents 78% of that capacity.

Figure A: Locations of DESC's Generation Assets



In addition, DESC's principal interconnections with Duke Energy Carolinas, Duke Energy Progress and Georgia Power are located in the northern region.

Q. DESCRIBE HOW THE STATE OF GENERATION ASSETS IN THE LOW COUNTRY IS EVOLVING.

A. The state of generation assets in the Low Country, and coastal region of South Carolina more generally, has actually changed quite dramatically in recent years. In

2012, Santee Cooper retired Grainger station, a 170 MW coal plant located near Conway, South Carolina and Jeffries station, a 398 MW coal plant located in Moncks Corner, South Carolina. Additionally, a large source of generation in the Low Country formerly was DESC's Canadys plant, a 400 MW coal station located in Walterboro, just 20 miles outside of St. George, South Carolina. This plant was ultimately retired in 2013. Now, the only other large-scale generation resources currently sited in the Low Country are DESC's Williams station (610 MW) and Jasper station (852 MW), and Santee Cooper's coal plants, Winyah station (1150 MW) and Cross station (2375 MW). As I will explain further below, the availability of this generation in the future is questionable at best. Santee Cooper has announced plans to retire its four-unit Winyah coal-generation plant (1150 MW), located near Georgetown, in the not-too-distant future. Santee Cooper has also stated that it may retire some or all of its four-unit Cross coal-generation plant (2375 MW) in Berkeley County. Santee Cooper's generation is important because DESC and Santee Cooper's systems overlap to a large degree. Their generation dispatch can greatly affect our transmission system and vice versa.

Q. WHAT OBSTACLES MUST BE OVERCOME FOR FUTURE GENERATION ASSETS TO BE SITED IN THE LOW COUNTRY?

A. Future coal plant retirements may require additional generation to be sited in the Low Country. But doing so will pose significant challenges. The area lacks high-volume natural gas pipeline infrastructure sufficient to support a new large combined cycle gas generation facility. A single such facility can require the same gas supply capacity as is needed to serve all the gas distribution customers in a city the size of Charleston or Columbia on a cold winter day. Considerations such as these contributed to Santee Cooper's decision to build its largest combined-cycle station (Rainey Station, 500 MW) in Anderson County near the Transco natural gas pipeline that serves it.[1] And with the planned Atlantic Coast Pipeline now cancelled, it will be challenging to site new combined-cycle facilities in the Low Country or coastal region of South Carolina and will require overcoming gas supply constraints. Because there is limited gas supply in the Low Country today, electric generation must be "transported in" via transmission lines for customers in the Low Country to have a reliable source of power.

Q. HOW HAS DESC'S RESPONSE TO THE CANCELLATION OF THE NEW NUCLEAR FACILITIES AFFECTED THE USEFULNESS OF THE TRANSMISSION UPGRADE PROJECTS?

A. DESC replaced the generation it was expecting from the nuclear project with generation resources obtained by repowering McMeekin station and purchasing the Columbia Energy Center. McMeekin station is a 250 MW coal-fired plant located north of Columbia. Rather than retiring it as planned, it was converted to natural gas fired status to supply needed generation capacity while meeting current

[1] "Proximity to a major natural gas pipeline is the primary reason Santee Cooper chose this site," said Bill McCall, Santee Cooper executive vice president and COO. Quoted in https://www.power-eng.com/1999/04/01/santee-cooper-plans-new-generating-plant/#gref

environmental standards. It is located in the Columbia area and in close proximity to the lines and other assets built as part of the Transmission Upgrade Projects. The Company also purchased the Columbia Energy Center, which is also located in the Columbia area, to supply an additional 540 MW of capacity. It is also located in close proximity to the lines built as part of the Transmission Upgrade Projects.

Q. HOW DO THESE SOURCES OF CAPACITY IMPACT DESC'S TRANSMISSION ASSETS?

A. Because McMeekin and Columbia Energy Center are located in the Columbia area, and considering the steady closure of major coal generating stations in the Low Country, the need to ensure that generation can be transported to the Low Country from the north is just as important today as it was when the Transmission Upgrade Projects were planned in 2008.

Q. DO YOU EXPECT THIS NEED TO CONTINUE TO BE THE CASE IN THE FUTURE?

A. Yes, in fact, I expect the number of coal-fired generation assets located in the Low Country to decrease further. All of the factors mentioned above will further stress DESC's transmission assets and increase its need to support power flows from north to south as made possible by the Transmission Upgrade Projects. The upgraded transmission assets are important to our ability to serve customers reliably and are becoming increasingly important each year.

Q. ARE THERE ANY OTHER REASONS THAT THE TRANSMISSION UPGRADE PROJECTS ARE CRUCIAL TO DESC'S SYSTEM?

A. Yes. While the need to transport power to the Low Country is a top priority, there are other reasons the Transmission Upgrade Projects are valuable to customers. Additional transmission capacity has also been required to deliver power into the rapidly developing area around Lake Murray, Chapin, Irmo and the Town of Lexington, and into the Interstate 77 corridor around Blythewood, Killian and northeast Columbia. Transmission Planning designed the transmission upgrades to meet those customer needs. These upgrades reinforce the ability to deliver power into these growing load centers both from the south, and reinforces the connection between this area in the Jenkinsville site, where 1,296 MWs of capacity are located today.

Q. ARE THE NEW LINES THEMSELVES MORE CAPABLE THAN THE LINES THEY REINFORCE IN THESE AREAS?

A. Yes. The new lines are all bundled, double conductor lines. Their current-carrying capability ~~as measured in impedance and amperage~~ is approximately double that of single conductor lines while their impedance is reduced by over 30%. All but one of the existing lines that the new lines supplement in the Lake Murray, Lexington, Chapin, Irmo, Killian and northeast Columbia areas are older, single conductor lines.

The VCS1–Killian 230kV Line is a good example of such a line. Before the Transmission Upgrade Projects were constructed, a key 230kV line serving Northeast Columbia was the Wateree-Killian 230kV line. This single conductor line began at Wateree Station in lower Richland County and was the primary 230kV line serving the area east of Columbia. It terminated at the Killian Substation, which is a primary source of power for much of Northeast Columbia. By 2007, load growth and the length of the line made the Wateree-Killian 230kV line increasingly inadequate to support the power flows and voltage required at the Pontiac and Huron Substations.

In effect, the VCS1–Killian 230kV Line provided a new stronger feed into the Killian Substation, offloading the Wateree-Killian 230kV line and reinforcing the 230kV loop around Columbia from the north. The VCS1–Killian 230kV Line is a modern, bundled conductor line with high capacity for its voltage rating. This line is a system improvement that was required to prevent System Operating Limit ("SOL") violations in this growing area. It is equally necessary today as it would have been if the new nuclear units had been completed.

In a similar way, the VCS2–Lake Murray 230kV Line No. 2 provides additional power delivery capability to serve the rapidly growing areas surrounding Lake Murray, Irmo, Chapin and the Town of Lexington. The Saluda River 230kV/115kV Substation now provides the means for power to be delivered to customers in the northern parts of the Columbia metropolitan area including West

Columbia, Cayce, Springdale and the western part of the downtown core of Columbia. The transmission facilities that were serving these locations before the Saluda River Substation was built are located in highly developed areas and would be very difficult and costly to expand, if it would be possible to do so at all. The VCS2–St. George 230kV Line No. 2 is tied into the new Saluda River Substation, creating an important path for power to be delivered into the western portion of the Columbia metropolitan area from either the northern or southern region of the system, rather than through what would otherwise be increasingly congested lines west of Columbia and along the Broad and Congaree rivers.

Q. HOW DO YOU RESPOND TO MR. MCGAVRAN' S ARGUMENT THAT ONLY 25% OF THE VALUE OF THE VCS1-KILLIAN LINE PROVIDES SYSTEM BENEFITS?

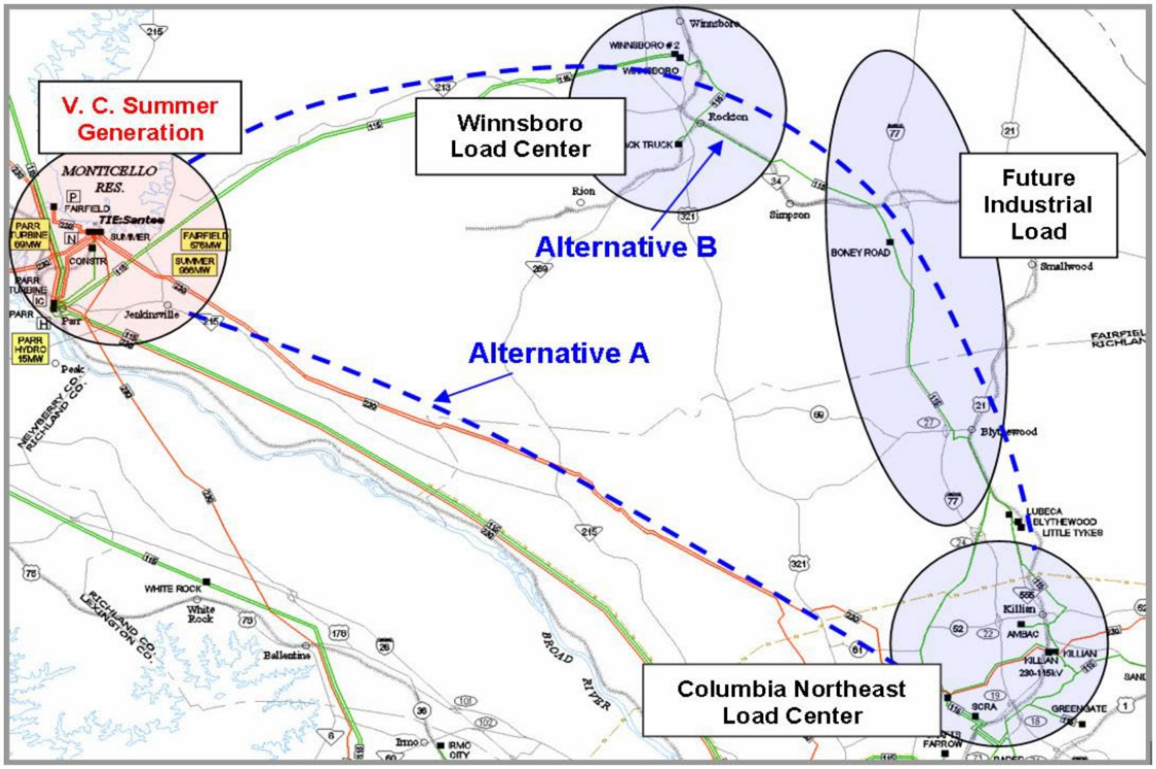
A. It is not accurate. One hundred percent of the VCS1–Killian 230kV Line provides system benefits that are critically important to our ability to serve the northeast Columbia area and avoid voltage issue in the area.

Q. WHAT WAS THE BASIS FOR SPLITTING THE COST OF THE VCS1–KILLIAN 230kV LINE BETWEEN THE NUCLEAR PROJECT AND OTHER TRANSMISSION INVESTMENT?

A. The split was based on the cost difference between two alternative routings of the line. Figure B is the map used in the Transmission Planning memo, dated July 26, 2007, approving the routing of the line.

Figure B

Alternative Routes of the VCS1–Killian 230kV Line



Alternative A was the most direct route for the line. It had the lowest up-front cost. Alternative B followed a longer, looping route that not only reinforces the transmission system serving the Killian Substation, but also can be used to serve future customers in developing load centers in the Winnsboro area and I-77 Corridor. Either route would prevent NERC violations by reinforcing service into the existing Columbia northeast load center. The longer line would do the same while also greatly reducing the cost to customers of serving future loads. Both routings of the line served the needs of the transmission system and would have benefited customers. Alternative B, however, was the most beneficial. The additional cost of Alternative B is the basis of the 25% allocation Mr. McGavran references.

Q. IN SUMMARY, HOW DO THE TRANSMISSION UPGRADE PROJECTS BENEFIT THE ENTIRE STATE?

A. The Transmission Upgrade Projects greatly improved the ability to move power from generation resources north and west of Columbia to the Charleston area. They also have allowed DESC to efficiently and reliably move power from the west side of the Broad and Congaree rivers to the I-77 corridor and northeast Columbia. Replacing the NND Project with the repowered McMeekin Station and Columbia Energy Center, and the retirement of Canadys Station and Santee Cooper coal generation, further established the value of the Transmission Upgrade Projects to customers and to the system. We could not operate the system reliably or in compliance with NERC standards without these assets.

Finally, I should mention that there has been significant development of solar generation in the rural areas in the center of the state. Prior to the Transmission Upgrade Projects, much of the power that flowed from north to south flowed over the network of 115kV lines in areas around Orangeburg and the Low Country. This was not ideal from an operational perspective under any circumstances as these lines use smaller conductors with corresponding lower thermal ratings and greater losses. Relying on these 115 lines for this purpose also results in the difficult-to-manage effects of an unplanned (contingency) or planned (maintenance) loss of one of these lines. But the consequences for solar developers was that the resulting periods of congestion would have limited our ability to site solar projects along 115kV lines in rural areas without expensive upgrades. (It is operationally preferable and less costly for solar facilities to connect to lines at voltage levels no greater than 115kV.) The Transmission Upgrade Projects offloaded those 115kV lines in rural areas and made it possible to site solar generation on them without the need for additional and expensive transmission upgrades.

Q. CAN YOU PROVIDE DETAILS?

A. Yes. In the Orangeburg and Beaufort areas, 659 MWs of solar have been added or are in the process of being added in areas where 115kV lines and certain 230kV lines that once carried significant north-south flows were offloaded by the Transmission Upgrade Projects. These are areas that are attractive to solar developers for siting their facilities. The Transmission Upgrade Projects reduced transmission congestion in these areas, so that the addition of solar can now be accommodated without expensive transmission upgrades. Furthermore, there is an additional 1321 MW of solar in the DESC interconnection queue that will be positively impacted by the Transmission Upgrade Projects if completed.

Q. HAS DESC PERFORMED TRANSMISSION PLANNING STUDIES TO VERIFY THE VALUE OF THE TRANSMISSION UPGRADE PROJECTS TO THE SYSTEM?

A. Yes. As Company witness Wade Richards explained in Docket No. 2017-370-E, after the NND Project was cancelled, the Transmission Planning group, which I lead, conducted transmission planning studies that showed that the Transmission Upgrade Projects were entirely necessary for the reliable operation of the transmission system with or without the NND Project. The studies modeled the transmission system assuming that none of these assets had been constructed. The results of these analyses are set forth on ***Exhibit __ (RSP-1)***. The analyses clearly justified the need for the Transmission Upgrade Projects.

Q. WHAT TRANSMISSION PLANNING STANDARDS WERE USED IN PREPARING THESE ANALYSES?

A. In preparing these analyses, my department followed the same standards and criteria that are used consistently in the Company's transmission planning studies under the mandatory North American Electric Reliability Corporation ("NERC") Transmission Planning Standards including NERC Reliability Standard TPL-001-4. Under this Reliability Standard, the Company is required each year to conduct a Planning Assessment of its transmission system for various on and off peak seasons within multiple time periods including: the next year, five years into the future, and six to ten years into the future. In preparing these analyses, Transmission Planning also applied the Company's system-specific Long-Range Planning Criteria, which supplement the NERC Transmission Planning Standards. The Long-Range Planning Criteria are transmission planning criteria that the

Company has adopted in light of its system attributes and consistently applies in its long-range transmission modeling.

Q. HOW MANY LEVELS OF CONTINGENCIES DID YOUR PLANNING GROUP MODEL?

A. Contingency events and conditions were modeled under the NERC Reliability Standard requirements that provide for multiple levels of analysis. The first includes the loss of any single transmission or generation asset (N-1). A second level of the analysis models the response of the system to the loss of any transmission or generation asset, followed by appropriate transmission switching and re-dispatching, and then followed by the loss of any other transmission or generation asset (N-1-1). A third level of analysis measures the simultaneous loss of two transmission or generation assets (N-2).

Under any of these circumstances, the goal of transmission planning is to ensure that system stability can be maintained and the stress on any transmission or generation asset would be held within acceptable limits. Exceeding these limits results in the model identifying a SOL violation. The failure to identify and mitigate SOL violations can result in widespread loss of service to customers and long-term damage to transmission or generation assets, which could make the restoration of electric service to customers an extended, difficult and expensive process. Failing to identify and take necessary steps to correct existing or forecasted SOL violations also constitute a violation of NERC standards, which can result in sizable fines and penalties.

Q. HOW DID YOUR PLANNING GROUP ANALYZE THE BENEFITS TO THE SYSTEM OF THE TRANSMISSION UPGRADE PROJECTS UNDER CONSIDERATION HERE?

A. In assessing the necessity and benefits of the Transmission Upgrade Projects that were part of the NND project, my planning group modeled the N-1, N-1-1 and N-2 scenarios for Summer Peak, Fall Peak, Winter Peak, Shoulder Load and Light Load for 2018-2019, 2019-2020, 2022-2023, and 2027-2028.

Q. WHAT DO THESE ANALYSES SHOW?

A. These analyses show that without the Transmission Upgrade Projects, there would be multiple SOL violations both now and in the future. Without the Transmission Upgrade Projects, a substantial number of the Company's transmission facilities would be overloaded or heavily loaded beginning in the near term, and the number of overloaded and heavily loaded facilities would increase as time progresses. Contrary to Mr. McGavran's testimony, a number of these issues were identified in the 2018-2021 timeframe, not just in the year 2028 as he seems to believe. In short, without these upgrades we would be in serious violation of NERC standards on day-one, and those violations would increase over time.

Q. CAN YOU PROVIDE DETAILS OF THE SOL VIOLATIONS?

A. Yes. Without the Transmission Upgrade Projects, thirty-seven 230kV and 115kV transmission lines, totaling approximately 571 miles, will be overloaded or heavily loaded, and eight high-voltage transformers will be overloaded or heavily loaded, totaling 2352 MVA of transformer capacity. Having allowed these SOL violations to rise to this level, it is likely that NERC would find DESC to be in serious violation of its responsibilities under Federal law. Transmission upgrades of the sort provided by the Transmission Upgrade Projects would be required to correct these problems as quickly as possible.

Q. HOW MANY MILES OF LINE AND MVAs OF TRANSFORMER CAPACITY WERE ADDED AS A PART OF THE TRANSMISSION UPGRADE PROJECTS?

A. The Transmission Upgrade Projects improved 376 miles of 115kV and 230kV lines and added one high voltage transformer with a capacity of 336 MVA. The scope of the Transmission Upgrade Projects is in no way out of line with the extent of the problems that they have allowed our transmission system to avoid.

Q. HOW DOES THE OUTPUT NOW FLOWING ON THE TRANSMISSION UPGRADE PROJECTS FROM THE GENERATION RESOURCES THAT REPLACED V.C. SUMMER UNITS 2 AND 3 COMPARE TO WHAT FLOWS FROM V.C. SUMMER UNIT 1?

A. One of the tools used by Transmission Planning when assessing our transmission system is to calculate values called Generation Shift Factors (GSF). A

GSF value represents the percentage of the output of a given generator that flows on a given transmission facility. Our department compared the GSF values of V.C. Summer Unit 1 with those of the generating resources that replaced Units 2 and 3 on the new St. George 230kV lines. The analysis shows that the generation output of McMeekin and Columbia Energy Center that flows on the two new lines to St. George is comparable and, in some cases, greater than that of V.C. Summer Unit 1. Table 1 sets forth the generation flowing on each from the different generation resources.

Table 1

Orangeburg East – St. George 230kV	
Station	**% of Unit Output Flowing on the Line**
McMeekin 1	4.1%
McMeekin 2	4.1%
CEC 1	5.0%
CEC 2	5.4%
CEC 3	5.3%
VCS 1	4.5%
Saluda River – St. George 230kV	
Station	**% of Unit Output Flowing on the Line**
McMeekin 1	9.0%
McMeekin 2	9.0%
CEC 1	7.3%
CEC 2	5.9%
CEC 3	5.9%
VCS 1	6.9%

Q. WHAT DOES TABLE 1 ILLUSTRATE?

A. Table 1 illustrates that the value of these assets is in no sense specific to generation located at the V.C. Summer site but that they are used and useful to the transmission system as a whole as it exists today. It shows that these lines are indeed being used to deliver power from the Columbia area, and specifically the resources that have replaced the V.C. Summer Unit 2 & 3 capacity, to customers in the Low Country.

Q. BOTH MR. MCGAVRAN AND MR. SEAMAN-HUYNH CRITICIZE THE NEW LINES AS BEING "UNDERUTILIZED." IS IT FAIR TO CLASSIFY LINES AS "UNDERUTILIZED"?

A. No, it is not. It is critical to understand that maximizing the utilization of a new transmission facility is in no way the goal of the transmission planning process. A sound transmission planning process must model multiple flow states on the transmission system across a comprehensive range of assumptions as to customer demands and availability of generation and transmission resources. These studies do not seek to meet some predetermined capacity utilization for a transmission system. Instead, they seek to identify which lines would be overloaded or heavily loaded under reasonably foreseeable N-1, N-1-1 and N-2 conditions as NERC reliability rules require. The studies then seek to identify the least-cost configuration of new lines or other assets that must be added to the system to relieve the overloading of the facilities in violation of SOL criteria. The resulting loading or capacity utilization of the new lines or other facilities is not considered because maximizing the percentage utilization of a given line is not a goal of the transmission planning process nor is it desirable.

However, since the issue of utilization of these new lines has been raised, it is important to explain that there is no benchmark percentage utilization of transmission lines by which to determine under or over utilization as Mr. McGavran and Mr. Seaman-Huynh seem to imply. I would note that nowhere in testimony did either witness present any evidence of what percentage of utilization would be appropriate—that is because there is no standard or determinative value to present.

Q. WHY IS DESIGNING TRANSMISSION LINES AND OTHER FACILITIES TO MEET CAPACITY UTILIZATION MEASUREMENTS NOT DESIRABLE?

A. Designing a line to operate at high capacity on the day it is built or shortly thereafter means that this line will have to be replaced or otherwise off-loaded when system conditions change. Transmission lines and equipment come in standard increments. The incremental cost of building a line with sufficient long-term capacity from the beginning is much less than the cost of building a small line now and additional lines later. My department would never aim to down-size a line to maximize its capacity utilization. To do so would be contrary to good transmission planning practices. Rather, the goal is to reduce loading on overloaded and heavily loaded lines in the most cost-effective manner possible for the long-term reliability, resiliency and efficiency of the system.

Q. WHAT CONSTITUTES AN UNACCEPTABLE LOADING OF A TRANSMISSION OR GENERATION ASSET AND WHAT MUST YOU DO IN RESPONSE?

A. The operative loading factors that are relevant here concern the thermal loading of transmission assets, including lines and transformers. Under mandatory NERC requirements, a plan must be formulated and implemented to correct or mitigate any thermal loading that exceeds 100% of an asset's thermal rating. Under the Company's Long-Range Planning Criteria, any asset that is shown in long-range analysis to be susceptible to being thermally loaded to 90% or more of its thermal rating is considered heavily loaded. A plan must be undertaken to correct or mitigate that loading before it occurs.

Q. WHAT ABOUT LINES LOADED TO 70% TO 80% OF THEIR CAPABILITY?

A. Likewise, loading at 70% or 80% is not desirable. Electricity moves at the speed of light. If a highly loaded 230kV line trips, all the power it carries instantaneously flows elsewhere, and this can overwhelm the 115kV system in a moment. Additionally, if all lines are heavily loaded, when one line trips, the power on the that line can flood over to other heavily-loaded lines, causing them to trip. The extreme result would be a cascading outage event. Operating a system with lines routinely loaded at 70% to 80% can put reliable service to customers, and the transmission grid as a whole, at risk. For these reasons, transmission systems are not built to operate at or near capacity either on average or on peak days.

Q. UNDER NERC RULES, IS TAKING ACTION TO CORRECT OVERLOADED OR HEAVILY LOADED LINES OPTIONAL?

A. No. When our planning studies identify a SOL violation at any point in the planning period, we must determine—in that planning cycle—how that SOL violation will be corrected. This is a NERC requirement backed by Federal law and the enforcement powers of the FERC. Going forward, the corrective measure, for example, a new line or other upgrade, must be assumed to be completed at the time specified in the plan. The next annual plan will include the effects of that corrective measure as part of the system as it is modeled going forward.

Q. DO OTHER UTILITIES RELY ON THE COMPANY COMPLETING THE MEASURES IT HAS IDENTIFIED TO CORRECT SOL VIOLATIONS?

A. Yes. Our system is electrically interconnected with our neighboring utilities, and through them, with the entire Eastern Interconnection. When other utilities model their power flows, they incorporate assumptions as to how power will flow into, out of, and through our system, including the effects of the corrective measure that we have modeled.

Q. DO NERC AND SERC AUDIT AND VERIFY WHETHER THE COMPANY IS PROPERLY PURSUING AND COMPLETING THE MEASURES IT HAS IDENTIFIED TO CORRECT SOL VIOLATIONS?

A. Yes. In auditing our transmission planning system, NERC and SERC consider not only how well we model it, but how well we carry through on the corrective measures we have modeled and communicated to our neighbors. In the appropriate circumstances, not following through with measures identified as needed to correct future SOL violations can itself be a serious violation of NERC standards.

Q. OTHER WITNESSES QUESTION THE LOADING OF DESC'S TRANSMISSION ASSETS BUT DO NOT PROVIDE ANY DATA CONCERNING LOADING CONDITIONS ON OTHER TRANSMISSION SYSTEMS. HAVE YOU IDENTIFIED SUCH DATA?

A. Yes. Certain other witnesses claim that the Transmission Upgrade Projects are not useful because their peak loading values for the test year (2019) were 20-26%. It is not the case that lines loaded at these levels are underutilized. My group has computed the percentage loading of 230kV transmission branches across the Eastern Interconnection, which is one of the three major power grids in North America and reaches from Canada down to Florida. The percentage loading on 230 kV branches on the Eastern Interconnect has been consistently around 19% at time of summer system peak for some time. Table 2 shows the average loading of 230kV branches at peak and non-peak periods as predicted for 2021 for Southeast utilities[2] and the Eastern Interconnection. Note that these are average loading figures and individual lines would have loadings that would be lower than these numbers.

Table 2

Case	Average 230kV Branch Loading (% of Thermal Rating)	
	Southeast Utilities	**Eastern Interconnection**
2021 Light Load	11.8	14.3
2021 Fall Peak	17.7	19.3
2021 Spring Peak	19.4	21.2
2021 Winter Peak	18.3	19.6
2021 Summer Peak	21.5	22.9

The implication in Mr. Seaman-Huyuh's testimony that transmission systems can or should operate at high capacity factors is simply wrong. The implication that DESC's transmission system operates a loading levels that are inconsistent with transmission systems in the region and throughout the Eastern Interconnection is also wrong.

Q. IN PRESENTING TABLES 5 AND 6 OF HIS TESTIMONY, MR. SEAMAN-HUYNH'S QUESTIONS WHETHER THE TRANSMISSION UPGRADE LINES ARE FULLY UTILIZED. HOW DO YOU RESPOND?

A. Contingency loading is the basis for all transmission planning. Mr. Seaman-Huynh's Table 6 provides the contingency loading of these upgrade project lines.

[2] Specifically, DESC, Duke Energy Progress, Duke Energy Carolinas, Dominion Energy Virginia, Santee Cooper, Southeastern Power Administration, Southern Company, and PowerSouth.

The average loading of these lines is over 25%. This is a reasonable number. Again, as mentioned above, these lines were not built to meet a specific capacity level, but to prevent overloading at any point on the system. The fact that a line may have a low capacity utilization does not at all indicate that it is not functioning as intended or providing a vital service to the system by preventing major problems elsewhere. Indeed, as mentioned previously, but for these Transmission Upgrade Projects, numerous SOL violations would exist.

Mr. Seaman-Huynh's Table 5 shows base loading numbers. Base loading has no bearing on transmission planning. The base load snapshots presented in Mr. Seaman-Huynh's Table 5 were prepared in response to ORS discovery demands. They do not reflect contingency scenarios but assumed all Low Country coal-fired generation was running at or near full capacity. This non-contingency scenario is a best case scenario in many ways and involves reduced power flows across the system. It is not the case for which they system is planned. The transmission system is planned for contingency situations, so that it will not to fail when reasonably foreseeable contingencies place maximum stress up it. Modeling numbers such as those presented in Table which do not reflect contingency loading are not relevant to the need for transmission facilities, or their usefulness and value to customers.

Q. HOW DOES THE DATA CONTAINED IN TABLE 5 COMPARE TO ACTUAL OPERATING EXPERIENCE?

A. Mr. Seaman-Huynh's Table 4 represents the actual maximum loading (not contingency loading but actual loading) experienced on these lines during 2019. It averages 22.8%. I have reviewed the comparable 2020 data and it is entirely consistent with the 2019 data. These percentages are also fully in line with national and regional percentages as presented earlier in my testimony. The actual experience of the system presented in Table 4 shows that the base case loading figures in Table 5 are unreasonably low. Table 5 in no way represents meaningful transmission planning data nor does it support the conclusion that these lines are underutilized.

Q. FINALLY, ARE THERE ANY OTHER BENEFITS TO THE TRANSMISSION UPGRADE PROJECTS?

A. Yes. As Mr. Kissam explained in his direct testimony, the Transmission Upgrade Projects improved both the reliability and resiliency of the DESC transmission system. Prior to improvements, the existing facilities consisted of direct-embedded wooden-framed structures, many of which were 40 years old or older. These facilities have lower performance, higher maintenance costs, and a shorter life expectancy than the alternatives commonly used today. The Transmission Upgrade Projects utilize stronger materials and newer design standards that increase asset performance, reduce maintenance costs, and increase life expectancy. They use bundled aluminum conductors and enhanced hardware and are attached to self-supporting steel structures capable of withstanding increased loading conditions due to wind and ice. By hardening the transmission system, the Company has greatly reduced the likelihood of damage or other detrimental impacts caused by extreme weather events, such as hurricanes, ice storms and other storms, and is also increasing its ability to restore service quickly after an event. Additionally, rebuilding the lines from a horizontal configuration to a vertical configuration allows DESC to maximize power flow through the existing right-of-way, which increases the reliability of the transmission system.

Q. ARE DESC CUSTOMERS REALIZING THE BENEFITS OF THESE IMPROVEMENTS?

A. Yes, the Transmission Upgrade Projects are already providing both immediate and long-term benefits. By enhancing and modernizing DESC's transmission system with these assets, DESC has experienced improved reliability and had the opportunity to eliminate other transmission upgrades that would have been required absent the Transmission Upgrade Projects. These facilities also provide enhanced interconnection between DESC, Duke Energy Carolinas and Santee Cooper and provide greater opportunity for these systems to provide support for each other. These assets are in every respect used and useful.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS FOR THE COMMISSION?

A. The analysis that Transmission Planning has conducted clearly shows the benefits of the Transmission Upgrade Projects to the safe and reliable operation of DESC's transmission system even with the cancellation of the NND Project. Without the Transmission Upgrade Projects, the system would fail to meet statutory Reliability Standards requirements today, and the situation would grow progressively worse with time. These Projects are just as important and just as useful, if not more so, than they were when originally planned in 2008. In addition, the Transmission Upgrade Projects consist of upgrades to the core assets allowing DESC's system to deliver power between the northern and southern regions of the transmission system. Transmission upgrades to support service to growing customer needs would be required with or without the addition of new nuclear generation to the system. For these reasons, the Transmission Upgrade Projects constitute assets which are used and useful in providing electric service to DESC's customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.